EXHIBIT C
to
Initial Comments of RealEnergy et. al.

Testimony of Dr. Howard Feibus before the California Public Utilities Commission

BEFORE THE

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060.	)))))	R.02-01-011

DIRECT TESTIMONY OF DR. HOWARD FEIBUS

Q. 1: Please state your name and business address.

A. 1: My name is Howard Feibus. My business address is 2111 Wilson Boulevard, Suite 323, Arlington, Virginia.

Q. 2: By whom are you employed?

A. 2: I currently am Vice President, Business Development for Electrotek Concepts, Incorporated (Electrotek) a consulting firm that focuses on the electric power industry in general and, more specifically, the evaluation and benefits of emerging electric generation and storage technologies.

Q. 3: Please describe your educational and professional experience.

A. 3: I hold a Bachelors degree in physics from Brandeis University, a Masters degree in engineering from Penn State University, and a Doctoral degree in physics from New York University. Since obtaining my PhD., I have been employed by various public and private entities and have focused on distributed generation and developing and evaluating the potential costs and benefits of commercial and newly emerging technologies to produce electricity from various fuels. The entities for whom I have worked include Bell Laboratories, Consolidated Edison, and the Energy Research and Development Administration, which was the predecessor to the United States Department of Energy (DOE). I also was employed for 21 years with DOE where my projects included the development of equipment to control precursors of acid rain, which lead to the establishment of the Clean Coal Technology Program, and the reformulation of the technology development effort to respond to concerns about greenhouse gas emission from fossil-fired power plants. Appendix A identifies a number of projects I have managed and conducted for Electrotek that are directly relevant to the subject of my testimony in this proceeding.

Q. 4: On whose behalf are you testifying in this proceeding?

A. 4: I am testifying on behalf of Clarus Energy Corporation, a party to this proceeding. Clarus Energy is a distributed generation services provider, which markets and installs stand-alone electric energy generation devices.

Q. 5: What is the purpose of your testimony on behalf of Clarus Energy in this proceeding?

A. 5: The purpose of my testimony for Clarus Energy in this proceeding is to discuss and quantify the numerous benefits which distributed generation provides to California's electricity market and to the citizens of the State. For Clarus Energy and the rest of the distributed generation industry, this is important in the context of the proposal before the California Public Utilities Commission to impose some type of exit fee on "departing load" customers. Clarus Energy believes that imposing an exit fee on customers who satisfy all or a part of their electric load by installing distributed generation systems is wrong, short-sighted, and contrary to public policy. However, if an exit fee is imposed on distributed generation customers, Clarus Energy believes that any such exit fee must be offset by the quantifiable benefits, which distributed generation (DG) provides to the electric generation, transmission and distribution systems, to the environment, and to the State's economy.

Q. 6: Please summarize your testimony.

A. 6: My testimony provides a quantification of the economic value provided by DG

?? To the customers served by the electric power system of California; and

?? By customers that install distributed generation (DG) systems.

A discussion is presented of Electrotek's experience with

?? Quantifying the costs and benefits of DG projects; and

?? Aggregating DG customers to enable the values of their DG capacity (and the energy supplied by that capacity) to be recognized in a centralized, wholesale electricity market.

The discussion of Electrotek's experience is followed by a calculation of the economic benefits provided by a typical DG project located in the State of California. Here, I would like to observe that in the regions served by ISOs, which administer a capacity market (NY, PJM), we find more encouragement for DG installations simply because one of the important benefits DG provides, electric generating capacity, is recognized economically by the market. In fact, an important goal of my testimony is to make transparent the importance of capacity, which is hidden in the price that California citizens pay for electricity.

This testimony will quantify the value of a typical DG project located in the State of California, from the perspective of the economic benefits that it provides to California's electric power supply and delivery system. The summary results of that estimate are shown below:

CASE STUDY: Gas Engine Generator Benefits

Per Unit Value of Benefit	**$/kWh**
Capacity value	**0.0140**
Unexpended Energy	**0.0130**
Transmission Line Delay	**0.006**
Avoided Distribution Investment	**0.003**
Avoided T&D Losses	**0.001**
NO_x Avoided thermal energy production	**0.0006**
Avoided CO_2 Emissions	**0.0004**
TOTAL	**0.038**

Figure 1: Generic DG Location Points Within a Distribution System

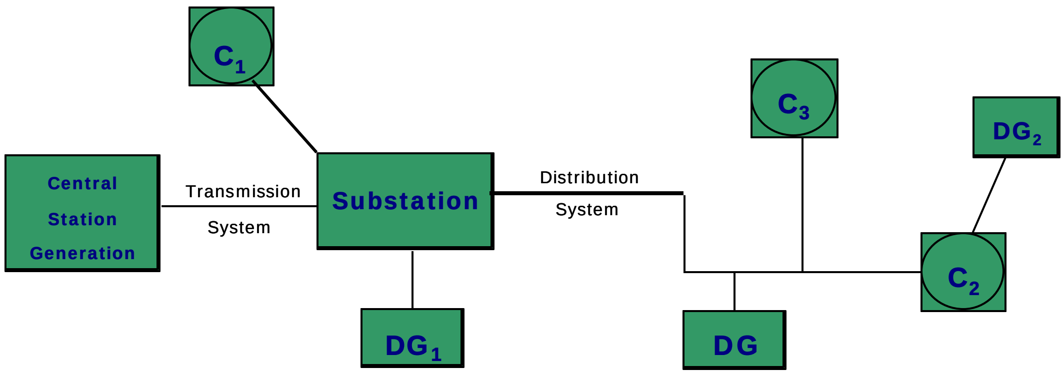
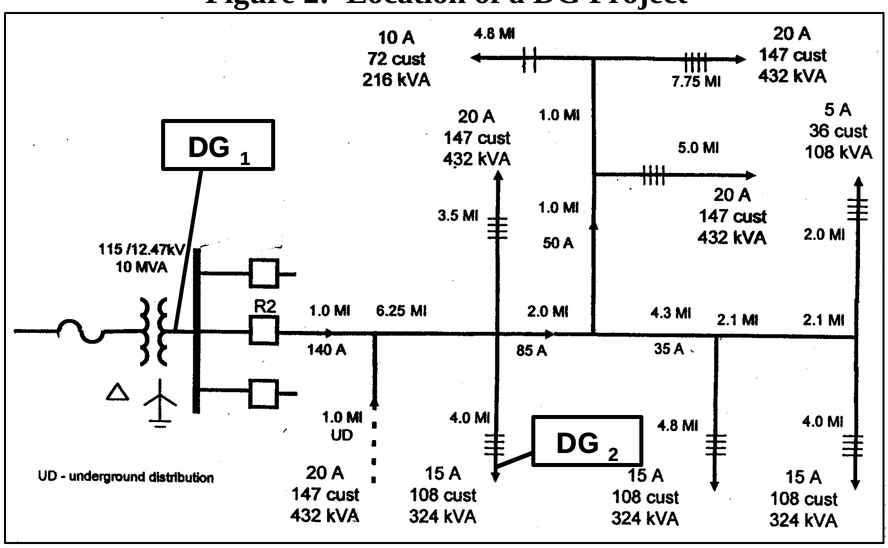


Figure 2: Location of a DG Project



Q. 7: What is the definition of DG?

A.7: Figure 1 shows an idealized view of an electric power supply system, which evolved into a system that was supplied by increasingly large central station power plants, that were connected to its end-use customers by a complex set of transmission (high voltage) lines, arranged to feed a large number of substations, where the high voltage is transformed to medium voltage for distribution to the ultimate customer. Figure 1 includes the essential elements of a utility system: generation, transmission, and distribution. Most of the electrical generating capacity in the United States is comprised of large central stations that are connected to a transmission (high voltage) system that, in turn, is connected to a distribution (medium voltage) system. In the figure, DG blocks are indicated. DG_1 is connected to a distribution substation. The main element in the distribution substation is a transformer that converts the transmission voltage to a primary distribution voltage. From the substation, a number of primary distribution lines carry power to step-down transformers, converting the primary distribution voltage to a low voltage for delivery to the customer (C). DG_2 is connected close to or at C_2, which represents an end-use customer load, where the DG unit may yield additional locational (e.g., waste heat utilization) and operational benefits (e.g., reduce demand on the distribution system). Figure 2 illustrates a bit of the infrastructure that exists between the substation (shown to the left of DG_1, which has the same meaning as in Figure 1) and the end-use customer. Figure 2 is included to illustrate the fact that DG can function in many dispersed locations. A distribution substation may serve as many as several hundred to a thousand customers. DG benefits can accumulate to have an impact to the electric power system greater than a multi-megawatt powerplant.

The system described above has evolved over many years as the U.S. power supply system increased in capacity. The system shown in Figure 1 enabled larger power plants to be integrated into the system, and these ever-larger systems became the focus of utility planners in the middle of the last century. What that focus led to was a lost appreciation of the benefits from locating some generation close to the end-use customer.

Distributed Generation, labeled DG in Figures 1 & 2, is any electric generator, whether or not it is tracked and scheduled by the transmission system operator, that is located on the medium voltage side of the substation, or closer to the end-use customer. Qualitatively, DG_1 units can provide capacity, help alleviate congestion on the transmission system, and possibly help delay the need to construct a new or additional transmission line. DG_2 can also provide these benefits, and additional ones as well. Because of its location, DG_2 can help alleviate congestion on the distribution system and it can provide specific benefits that can only be captured by the end-use customer; such as emergency backup service and waste heat utilization.

Q. 8: What kinds of benefits can DG provide?

A.8: Electrotek has conducted a number of studies for the U.S. Department of Energy (DOE) and Conectiv Power Delivery, which is a major electric distribution company operating in New Jersey, Delaware and Maryland. The purpose of the studies was to determine the potential for DG to help alleviate the supply of power to the Delmarva Peninsula, an area with significant concerns about power supply, and sensitivities toward environmental degradation.

Collaborating with Conectiv, the approach that Electrotek used was to simultaneously analyze the problem of supplying electricity to the consumers on the Delmarva Peninsula, over a ten-year period. The Delmarva Peninsula is a six thousand square mile area south of Wilmington Delaware, that includes portions of Maryland and Virginia. Delmarva is similar to many areas of California, where the growth from nearby metropolitan areas (Washington, Baltimore, Wilmington) is spilling into rural areas, causing stress on the electrical supply system, which is straining to support the growth in demand.

One of the unique features of the study is that, simultaneously, the flows in the transmission system were balanced with the loads in the various distribution planning areas, down to the level of a distribution system. This is shown in Figure 1, which allows for projects located at C_1 as well as at C_2 to be analyzed. This enabled the benefits of reduced transmission impacts to be quantified. It also allowed for more detailed information about projects located at end-user locations, such as depicted in Figure 2. This includes the type of planned inter-connection with the utility grid. In this way, a conventional power supply plan was developed, requiring the construction of a new 500 kV transmission line. The costs of this plan were compared to locating DG units in various distribution planning areas. By this technique, we were able to examine the impacts upon costs and reliability of locating various capacities of DG at various locations. The major findings support a conclusion that DG can help maintain system reliability and lower costs, if ways were identified to easily identify and quantify the benefits.

In fact, the study was able to catalog the benefits and develop simple algorithms to estimate their values for specific locations/applications. For a specific project, the results are a set of outputs, such as is shown in Figure 3. The outputs of the analysis depend upon the specific type of interconnection and applications, as shown for the set of cases identified in Figure 4 and the capital costs shown in Figure 5, where the analysis for Figure 3 corresponds to Case 3.

Figure 3: DG Benefit ($000) and Payback Analysis

	Case i –1250
Capacity Value *	45
Revenue from Energy Sales (ISO)	NA
Electric Energy Saving	320
Waste Heat Savings (EU)	168
Backup Service Credit (EU)	48
T Invest. Defer. Saving (VAR)	19
D Invest. Defer. Saving (UDC)	9
T&D Energy Loss Saving (TBD)	3
Emission Reduction Sales (TBD)	1
GHG Reduction Credit (TBD)	1
Green Energy Sales (TBD)	NA
Economic Dev. Credit (UDC)	NA
Total Benefits	**614**
Total O&M Cost	162
Delivery Charge	
Standby Charge	50
Total Annual Cost	**212**
Net Revenues	**402**
Payback Period, Year**	**3.1**

*Presently there is no market for the sale of this capacity, as long as the end-use customer is supplied by the distribution company.

**Simple payback is the ratio of capital cost to net revenues.

Figure 4: Cases Analyzed Using Different Interconnections/Applications

Case #	Configuration
1	Peaking + Power Export to ISO
2	Base-load + Power Export to ISO
3	Base-load + Waste Heat Recovery
4	Peaking + No Grid Connection
5	Existing Peaking + Power Export to ISO

Figure 5: Capital Costs ($000) Corresponding the Cases Analyzed

Case #	1	2	3	4	5
DG Technology			400-750		
Heat Exchanger			150-300		
Absorption Refrigeration					
Interconnection			50-100		
Aggregation			0		
Gas Compression			100		

Figure 3, for the cases chosen, shows the annualized benefits (waste heat credit, etc.) for each of the cases and compares them to the annualized costs, enabling one to calculate a simple payback, which is a useful figure of merit for a potential project. For illustration the specific project benefits may include the following:

1. ***Electric Generating Capacity*** **-** As a power source that is integrated with the operation of the electric power system, DG can be certified to participate in competitive electric markets, where they exist, and where capacity is recognized, economically, even if not electrically inter-connected to the electric distribution system. Where competitive markets have not been established, electric utilities or energy service providers may contract to make capacity payments to the independent power generators. It is a reservation payment to the generator owners who have agreed to operate their generators in response to an activation call. This recognition of the value of DG measures the value of the DG on the same scale as it does for any generator that is certified to operate on the transmission grid.

2. ***Electric Energy -*** For DG projects, in which capacity has been sold, the owner of the capacity is obligated to operate the DG in response to an activation call. Where this is done in a competitive environment, the analysis will provide an estimate of prices at the times the unit is expected to run; average run prices will be based upon historical prices in the region where the project is to be located and upon the application: peaking or co-generation or baseload. The market clearing prices in most central markets, including California, recognize the value of transmission in the form of congestion charges, which increase the market clearing prices for a constrained area, to the extent needed to provide an alternate supply source that avoids the transmission bottleneck.

3. ***Electric Energy Saving –*** For projects in which the owner intends to operate his generator instead of purchasing electricity from the distribution company, energy savings are based upon the costs that would have been incurred. It is envisioned that DG can act as a hedge on high electricity prices and can reduce exposure to market price volatility. In the same way as when the energy is being sold in the central market, energy savings result in avoiding payments for electricity when the DG unit operates. The DG used in this way provides the same economic benefits to the system as when the electricity is being sold: congestion is relieved, reducing congestion costs, and in fact market clearing prices will be reduced as a result of the operating DG units.

4. ***Sales to Thermal Energy Loads -*** Through Combined Heat and Power (CHP) applications, DG can produce steam or hot water for use in manufacturing processes or for space heating and cooling. Utilizing the waste heat produced from DG, the overall system efficiency can increase to 70% and higher, which can reduce or eliminate the need for additional thermal energy to supply load. The value of this thermal energy is accounted for as a sale to the end-user, who may also be the owner of the DG.

5. ***Backup power supply and Increased power reliability –*** With the addition of appropriate switching equipment, the DG unit can be isolated when the utility is unable to supply the area, thereby serving as a backup generator to avoid power outages and the resulting safety and productivity concerns associated with the loss of grid power.

6. ***Transmission Upgrade Deferrals*** - Utilities can use DG as a way to relieve transmission congestion and defer their investments in transmission system upgrades or new investments. The value of these deferrals is quantified and the portion attributed to the DG project assigned.

7. ***Distribution Upgrade Deferrals -*** Utilities can use DG as a way to relieve congestion in the distribution system and defer their investments in distribution system upgrades or new investments. The value of these deferrals is quantified and the portion attributed to the DG project assigned.

8. ***Reduced transmission & distribution electric loss*** - DG avoids electric losses associated with transporting power. Depending on the transporting distance and the voltage of the line, the electric losses can range from 2% to 10%.

9. ***Environmental Emission reduction credits***- *S*ystems utilizing combustion technologies generate harmful air emissions including SOx, NOx, and particulates. Many regions already have active emission auction markets such as NOx and SOx as part of a strategy for emission trading and reduction. Renewable DG technologies such as wind, PV, and fuel cell, plus other combustion engines and turbines burning natural gas, will enjoy emission reduction credits equivalent to the values of emission trading markets, especially where a DG project includes co-generation. While it is difficult to sell small reductions, it is quite possible to package the reductions from a collection of small renewable energy projects.

10. ***Greenhouse Gas Reduction credits***- There is growing concern over greenhouse gas emissions, such as CO_2, from power generation. Those power producers that can demonstrate verifiable greenhouse gas reductions through increased energy efficiency or the use of renewable resources may qualify for tax credits.

11. ***Green energy sales-*** As a part of the growing interest in the production of green power, there is an emerging market incentive to encourage the deployment of

renewable energy projects. Many people wish to encourage the use of renewable energy and are willing to pay a premium for their electricity if it's derived from renewables. In many areas the local distribution company acts as a broker between buyers and sellers of renewable energy.

12. ***Economic Development Credit***- In certain cases where a DG project is located in an economically disadvantaged area, it creates local employment, such as personnel to operate the DG facility.

Arrayed in this way, one can easily see the relative importance of each benefit to the economic viability of the project, as well as to the entity that must pay for the benefit and decide whether or not the project merits consideration.

The output shown in Figure 3 assumes the project is to be owned by an independent entity (a third party-Independent Power Producer or the owner of the industrial plant where the project is to be located). It is also assumed that the project is located in the territory where there is an Independent System Operator (ISO) that administers a competitive electric market and that electric energy is sold into the market, consistent with the operating characteristics of the DG technology/application; for example, using historical market clearing prices for the last three years in the PJM Interconnection (the ISO that administers the markets of PA, NJ, MD, and DE), the simple-cycle gas turbine was only called to operate about 150 hours per year, while the co-generation plant operated profitably about 4000 hours per year.

It is noted that the output of the analysis is able to assign a value for the reduction of sulfur, nitrogen oxides (NO_x), and Greenhouse Gas (GHG) emissions. While it is not currently practical to expect to sell such commodities from a DG project, it is already feasible to aggregate small projects and sell NO_x and in the near future the same should be true for GHG emissions.

Q. 9: What experience have you had quantifying the value of DG?

A.9.a: Electrotek analyzed the problem of supplying the Delmarva Peninsula. Using tools developed by Electrotek that enabled us to study the entire transmission system plus some specific distribution areas, we quantified the cost of electricity (COE) over a ten-year horizon for a base case (selected by Conectiv the local utility) and compared the impact of using DG upon COE and power system reliability. Then, using the results, we conducted specific case studies (for a specific industrial/commercial customer) located in a small town on the Delmarva Peninsula. With support from DOE & the National Rural Electric Cooperative Association (NRECA), Electrotek then used the results to develop a simple screening tool that identified the costs and specific benefits of a DG project, from the perspective of the relevant parties (end-use customer, project developer, distribution company). This has resulted in the Industrial DG

Handbook that Electrotek is now putting into the form of an Internet-based screening tool that will allow planners to screen the potential costs and benefits of a potential DG project of interest. The screening tool will enable the user to examine a range of different technological options.

A.9.b The Industrial DG Handbook is used as a screening tool to calculate the costs and benefits of a potential DG project, located in a distribution planning area, such as the site depicted as DG_2 in Figure 2.

A.9.c: For the New York State Energy Research & Development Administration (NYSERDA), the agency that administers the New York State system benefits charge, Electrotek developed a methodology to evaluate the use of existing DG units for curtailable load programs and conducted a pilot 5 MW demonstration program. The positive output has been a popular new load curtailment program in New York State that was credited, by the NYISO, with helping to keep supply and demand in balance during a heat emergency in August, 2001. This project provided a demonstration of the impact that DG could have in improving the reliability of the electric supply system. The key factors in the impact that the program had were the economic recognition of the value of the capacity added and the demonstration that curtailment of loads is of equal value to added capacity.

For DOE & NYSERDA we are now conducting a demonstration that consists of aggregating a number of commercial loads, using backup generators (existing DG units), to curtail loads. This collection of aggregated curtailable loads comprises a virtual generator that competes, in the markets administered by the NYISO, with conventional central station generators, to sell energy and capacity. The backup generators are owned by the commercial buildings, with whom Electrotek has a contract, which enables Electrotek, the aggregator, to sell the capacity and energy in the competitive markets administered by an ISO. This has provided

- ?? Experience with estimating the costs and benefits of these DG units; and
- ?? Experience with actually realizing new value from DG units in a competitive, open market.

Q. 10: Please provide an illustrative example of how to quantify the benefits of a DG project, using an example that typifies a DG project located in California

A.10: The Industrial DG Handbook includes a simple spreadsheet, which can be used to estimate the benefits of a specific project. An example of the output table is shown in Figure 3, below, which can provide space to display an estimate of the benefits for a number of variations. For this testimony, numbers are entered only for case (i): a typical co-generation project located in a growing area of California.

Figure 3: DG Benefit ($000) and Payback Analysis

	Case i –1250
Capacity Value *	45
Revenue from Energy Sales (ISO)	NA
Electric Energy Saving	320
Waste Heat Savings (EU)	168
Backup Service Credit (EU)	48
T Invest. Defer. Saving (VAR)	19
D Invest. Defer. Saving (UDC)	9
T&D Energy Loss Saving (TBD)	3
Emission Reduction Sales (TBD)	1
GHG Reduction Credit (TBD)	1
Green Energy Sales (TBD)	NA
Economic Dev. Credit (UDC)	NA
Total Benefits	**614**
Total O&M Cost	162
Delivery Charge	
Standby Charge	50
Total Annual Cost	**212**
Net Revenues	**402**
Payback Period, Year**	**3.1**

*Presently there is no market for the sale of this capacity, as long as the end-use customer is supplied by the distribution company.

**Simple payback is the ratio of capital cost to net revenues.

The left column lists each of the benefits and, from the perspective of the project owner shows from whom he must receive revenues if the project is to recover his costs over a payback period that is shown on the bottom line. It is noted that a DG project involves a number of key players (the project owner, the end-use customer, the electric distribution company, the ISO, etc). If specific benefits are to be realized, by the project owner (the party that invests in the equipment) another party must pay. If the project provides thermal energy that can be used, the user must pay the project owner. The possibility exists that one party may be both the project owner and the end-use customer. In fact, the methodology (of which Figure 3 is a key output) enables one to quantify the benefits

AND identify the party that should pay. In fact, a key reason for this testimony is that certain benefits identified in Figure 3 are created by a typical DG project in California, but are not recognized economically by the markets that are administered by the CAISO. Other benefits, such as the T&D system benefits, are well recognized in California, and have been documented previously, e.g., "Targeting DSM for Transmission & Distribution Benefits: A Case Study of PG&E's Delta District" (EPRI, 1992).

From the first column, it can be seen that there are system benefits, which include

1) Capacity
2) Energy
3) Transmission System Investment Delay
4) Distribution System Investment Delay
5) T&D Loss Saving
6) Emission Reduction
7) GHG Reduction
8) Green Energy

Below, we will estimate the system benefits for a typical DG co-generation project that is probably most relevant to the issues raised by the imposition of exit fees. We will provide a quantitative estimate of the system benefits (i.e., the value) provided by a co-generation project to the citizens of the State of California. An attempt will be made to provide a conservative estimate of benefits. Conservative means that a reasonable person would agree that the actual benefit would be at least as high as the value estimated below.

The typical project for which the benefits will be estimated below, is characterized as follows:

- Spark ignited engine; 800 kW electric output
- Installed capital cost = $1250/kW
- 28% electric efficiency
- 4.214×10^6 BTU/hr captured heat (60% recovery)
- 48% thermodynamic efficiency (electric plus thermal energy)
- Load factor (electric and thermal) = 46% (assumes two shifts per day)

A.10.a: Quantifying the Benefits. For the project characterized above, using the methodology developed by Electrotek and described in the Industrial DG Handbook, the estimated benefits to the System (System refers to the California Electric Supply System whose markets are administered by the CAISO) are:

1) Capacity

Before providing an estimate of the capacity value of the co-generation facility, it is noted that very often an electric utility assigns no capacity value to such a project, but rather **imposes a standby charge.** The utility rationale is that the co-generation facility is not 100% reliable; therefore, the utility assumes the DG unit will not operate during the peak, imposing the same demand upon the electric system as any other customer who has no generation capability.

Given that there are many such DG projects, a more reasonable approach would be to de-rate the value of the capacity, as the utility practice has been to do for its own capacity (or did when it was vertically integrated) and as is done with capacity that is certified to supply electricity to the grid. For this estimate, we will assume a 10% de-rating factor, which is conservative. When you start the engine of your car – a similar technology – the probability that it will start and operate as long as needed is greater than .999, unless you forget to maintain it as recommended by the manufacturer or decide to drive through the desert. For this analysis we will apply a very conservative probability of 0.90.

The capacity value of the DG unit is independent of whether it is grid connected or operates in isolation from the grid. The facility in which the DG unit is located is integrated with the operation of the System and it reduces the need for electric system capacity to supply electricity to the end-use customer, who needs the same electric energy whether from the system or from the DG unit. From the previous thought, the DG unit has the same value as any electric generating capacity that is certified to inter-connect with the grid.

What is the value of this capacity? For the sake of providing a conservative estimate, assume that the value of the DG is equal to the **cost** of adding the next central station unit of peaking capacity. This is a relevant way to arrive at the value for a California application, since the State is growing and needs to add capacity, not only to provide for new growth, but also to supply the current deficit of capacity. At the present time, the critical capacity is peaking capacity to avoid system shortfalls during peak periods.

The installed cost of a new combustion simple-cycle peaking unit, including connections to the transmission system, is \$350/kW- \$500/kW for an 80 MW unit (actually two General Electric Frame 6 units). A unit being installed in New York State has a published cost of about \$1000/kW.

It is noted that the comparison of the value of an 800 kW DG unit with a 40,000 kW central station unit is apt. Central station units are large to achieve economies of scale, but can be replaced by a number of dispersed DG units. In fact, the number of 800 kW DG units to replace a 40,000 kW is not fifty, but is somewhat less. Fewer DG units are needed because by locating them at customer sites, the capacity to generate the losses is avoided. On average this amounts to about 10.8%, which is based upon the analysis (sponsored by DOE) that led to Figure 8. The construction of the estimate was done with an input from California utilities and is consistent with losses experienced in the electric power supply system of California.

The annualized value of the DG unit located at the customer site is

Annualized Capacity Value = (800 kW) x 0.9 x 1.11 x $350/kW x 0.16 = $44,800.

The per-unit annualized cost of money (0.16) is a factor that has that been developed for electric utility regulated projects, for which a lower rate of return is justified, since the utility unit does (or rather did) not compete in a market for electricity. The factor (0.16) is taken from the EPRI Technology Assessment Guide and has been used in annualized capital cost estimates by the Energy Information Administration of the U.S. DOE. It is a measure of the annual cost of using capital, and is as applicable to California utilities, as to others throughout the country.

And, the annual saving calculated above is consistent with a

Per unit capacity value = $44,800/ (800 kW x 4000 hr/yr) = $0.0140/kWh.

2) Energy

This next benefit is a system benefit, which comprises the energy that does not need to be supplied to the customer because the customer is co-generating. As noted in the characterization of the project, the thermodynamic efficiency of the operation is 48%. Here, thermodynamic efficiency is the ratio of useful energy (in the form of heat, that would otherwise have to be produced independently, plus electricity) to the energy content of the fuel consumed. To supply the same amount of electric energy from the utility system, the electric efficiency would be about 33 %, the average thermal efficiency of embedded electric generation capacity tied to the California transmission system.

If the customer did not co-generate, the System would need to generate an additional 3.37 x 10^6 kWh per year. Qualitatively, the system benefit provided by the on-site generation, in a competitive market, is that the need to buy that quantity of electricity on the market reduces the price of electricity, specifically by:

?? Reducing demand and allowing the market to clear at a lower price; and

?? Reducing congestion charges that require more costly generating resources to be used to balance supply and demand.

The unexpended system energy attributable to the co-generation project is

Unexpended System Energy =

= .800 kW x 0.9 x 1.11 x (3.414BTU/kWh) x 4.000 hr/yr x (1/0.33 – 1/0.48)] x 10^9 = 10.1 x 10^9 BTU/yr.

In California, the unexpended energy would have cost approximately $4/10^6 BTU (this is the '02 city-gate natural gas price, to date) for fuel or about $40,000/year (or, 10 x 10^6 kWh @ $0.012/kWh) and about $2000; where the variable O&M cost = $7 x$10^{-4}$/kWh.

Per Unit Unexpended Energy = $0.0130/kWh.

3) Transmission System Investment Delay

Transmission systems need to be expanded when their capacity limits are reached. At these times, it is not possible to serve all users and the System faces a bottleneck. One effect of congestion is to raise the market clearing prices of the energy delivered to the relevant nodes. The larger effect is to degrade the reliability of the System. The Electrotek methodology measures "Unserved Energy", or the number of kWh that are presumed not to be delivered to end-use customers due to inadequate transmission capacity. One way this has been experienced by many customers in California is through the use of rotating blackouts to balance supply and demand.

Installation of DG units make it possible to delay the construction of transmission lines to the extent of the DG capacity and avoided losses, to the extent that DG is supplied close to the load.

As part of a previous planning study, the transmission system and one distribution planning area were modeled using Electrotek's Disco Suite modeling tool. Based upon the results, a simple algorithm was developed – identifying the capacity of DG needed to defer the traditional investment to reinforce the distribution planning area for N years (this is a transmission requirement; energy supply to the area, as opposed to reinforcing the distribution capacity of the area), and divide by the number of years. The annual economic benefit equals the capital cost of the facilities that can be delayed, divided by N. While this is a simple, straightforward result, a key issue must be considered; that is, the number of units and the reliability performance of each unit must be comparable to the reliability afforded by the traditional investment in the distribution system

To analyze how the use of distributed generation can delay the construction of transmission lines, Figure 6 (on page 29) is provided. This exhibit is a measure of the transmission system reliability on the Delmarva Peninsula, although it is comparable to the California situation in that California has an electric supply deficiency and a need to relieve transmission constraints. The first curve (do nothing) shows that the unserved energy will increase sharply, unless the system is reinforced. The planning assumption of Conectiv, the owner of the transmission system, was to build a 500 kV transmission as shown in Figure 6.

Figure 6 measures the amount of unserved energy (UE), which is measured on the vertical axis. UE is the energy that would have been consumed if the transmission system could have enabled it to be delivered. UE is a key parameter that the Electrotek methodology tracks to help identify when new facilities must be added. Figure 6 shows that, due to growth in demand, the UE increases slowly, then tips up sharply when new facilities are needed. In order to maintain transmission system reliability (i.e., control the UE to an acceptable level), a 500 kV line will do the job for about eight years. Alternatively additional generation in the southern Peninsula will have about the same impact. This would essentially have maintained power system reliability for an additional seven years. To equate the value of transmission to generation;

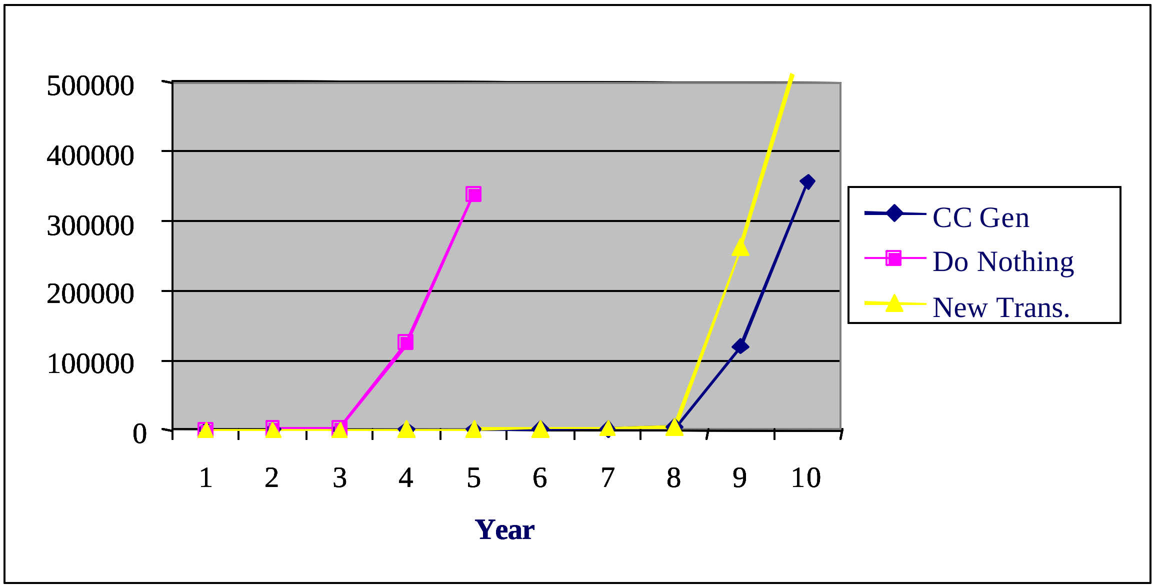
500 kV transmission line capacity =

Peak Demand (2000 MW) x Growth Rate (.02) x Years of Acceptable UE (8) = 320 MW

The UE curve that is labeled CC Gen in Figure 6 represents the impact that a peaking plant, located in the southern Peninsula, could have on the reliability of power supply (i.e., on reducing UE). Actually, an independent power producer constructed a plant comprising seven 45 MW gas turbine units (the calculation of capacity assumes one unit is always out for maintenance). The first three were operational as of the summer of 2000 and the remaining units came on line last year. Therefore, while the 500 kV line is still the base planning option for Conectiv, it can be postponed by eight years.

In addition, the line can be further postponed if distributed generation units are installed. Compared to the effectiveness of the transmission line in maintaining acceptable levels of reliability and reducing congestion charges, DG reduces the need to supply system losses and it is found that 300 MW, or (300/8) MW of DG per year for eight years can substitute for the line.

FIGURE 6: Unserved Energy (kWh x 1000) Versus Time



The cost of such a line was estimated to be \$ 110 million in 2000 dollars. The piece that can be applied to the typical DG project being analyzed is

Value of DG to 15 yr. Transmission Delay = \$120 x 10^6 x (0.8 x 0.95 MW/320 MW)/15 = \$19,000/yr.

The per unit value to delaying the transmission line = (\$19,000/yr)/ (800 kW x 4000 hr/yr)

Per Unit Transmission Line Delay = \$0.006/kWh

4) Distribution System Investment Delay

In contrast to the transmission system constraint (a typical problem with transmission systems, especially for long lines and periods of high demand, is to maintain the design voltage), the limiting factor in most distribution systems is due to thermal losses in the transformer and feeders. The conventional way to address the unacceptable losses in the distribution system is to add a new sub-station and associated feeders. The analysis that Electrotek conducted for the distribution planning area that was studied led to a rule of thumb that four MW of distributed generation (not providing for redundancy) in the planning area is needed to delay the construction of the needed upgrade by five years.

Figure 7: Losses in the Distribution Planning Area Rise Sharply

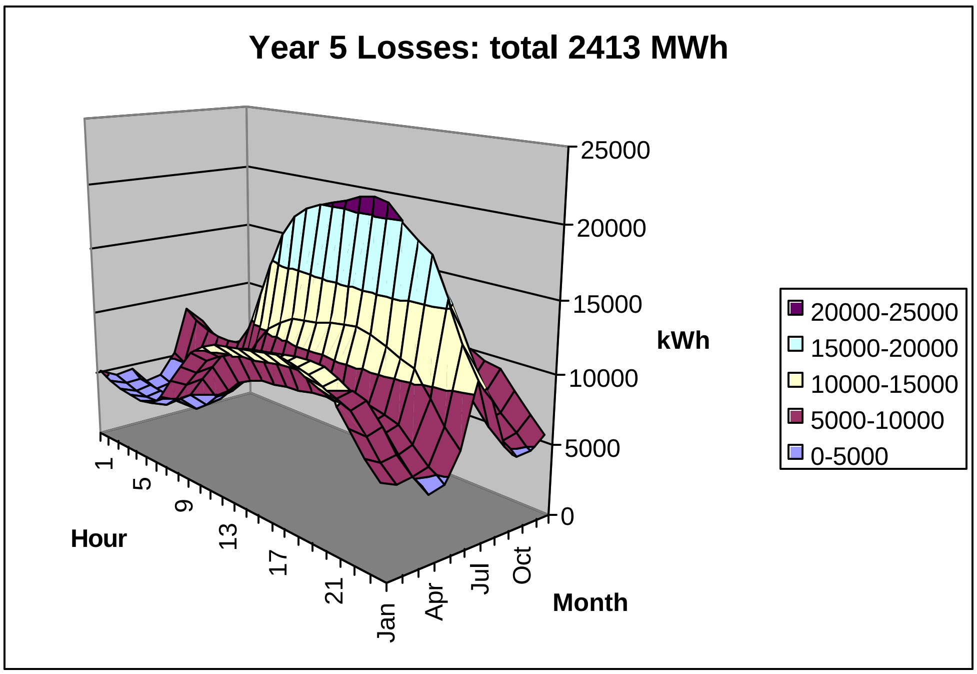


Figure 7 illustrates the classic problem facing the distribution planning area, which is typical of the fact that in California, weather conditions generally limit ability of a distribution system to meet demand. In the distribution planning area shown below the problem is the thermal limit that is exceeded for more hours each year as the demand grows. Figure 7 is a measure of the losses that continue to grow as the demand grows, and become excessive mainly during high peak demands (in the exhibit these occur during the summer months around the middle of the day). These growing losses will lead to increasing failures in the distribution system and reduced local reliability (in addition to the loss of the transmission system reliability) unless the distribution system is reinforced; either conventionally or with DG. Thus, Figure 7 illustrates the increasing losses that can be avoided by placing DG units, which do not contribute to the losses shown in Figure 7, at end-use customer sites.

The estimate for distribution savings is based upon a case where demand in the distribution planning area where the DG will be installed, is growing and a DG project can delay the need for new investment. The estimate used in the example assumes that a new substation plus additional lines would be built, but could be delayed by five years with the construction of 4 MW of DG projects, or $12k/MW/year.

Therefore, the per unit value of delaying the distribution planning area reinforcement is;

Per Unit Avoided Distribution Investment =

($12k/MW/year) x 0.8MW/(800kW x 4x 10^3)

Per Unit Avoided Distribution Investment = $0.003/kWh

5) T&D Loss Saving

For clarity, the energy saving calculated above, comprises a saving in the energy that would have been expended if the electricity consumed on site had been generated at a central station plant (33 % efficiency), instead in a co-generation facility (48 % efficiency).

Also for clarity, the T&D savings comprises two elements. The first is the capacity that is needed to generate the losses. This element has been included above in the capacity benefit. The second is the unexpended losses, which are estimated below.

A recent study estimated the average T&D losses for the U.S. The estimate is provided in Figure 8, below.

Figure 8: US Electric System Loss from Distribution

Distribution system	Loss as % of total
Step-up transformer T1	0.32
230 kV and above transmission	0.53
Step-down transformerT2	0.37
69 kV transmission	2.94
Step-down transformer T3	0.66
Meter	0.36
25 and 12kV distribution	2.94
Distribution transformerT4	1.77
Meter	0.90
Total	10.8

Source: Fourth Annual Distributed Generation and On-site Power, March 20-21, 1996 Four Points Sheraton, San Antonio, TX, DOE

For the purposes of this estimate the average losses comprise 10.8%.

The avoided T&D losses = 800 kW x 4000 hr/yr x (.11- .06) = 0.35 x 10^6 kWh/yr.

Value of avoided losses = $0.001/kWh.

6) Value of Emission Reduction

The electric generation that supplies electricity to the California grid is shown in Figure 9, and is comprised of:

Figure 9: CA Electricity Production*

Type	% Energy
Hydro	15
Nuclear	16
Coal	13
Natural Gas	38
Imports	10
Other	8
Total	100

*** Source; USDOE-EIA, Web-Site**

The implication of operating a co-generation facility is that less power will be generated from the natural gas units, and less power will be imported. The same amount of electricity is consumed, but System losses are avoided. This reduces the emissions of criteria pollutants: NO_x, SO_2 and particulate matter.

Based upon the structure of the installed electric generation in CA, approximately the same emission rate is experienced, regardless of whether the emissions are generated from central station plants or from the on-site generation unit. That means, the generation composition results in losses that are comparable to the emissions from a natural gas fired plant, with the exception of SO_2 emissions, which are relatively unimportant in CA, as coal represents only 13% of production. Given that the emissions are comparable to those from a gas-fired combined cycle unit, the assumption is made that the DG emissions are comparable to those of a gas-fired unit and the efficiencies are comparable.

However, when the electric generation takes place on site, the transmission and distribution losses identified above, amounting to 10.8%, do not occur. DG reduces emissions by that amount. Again, given the structure and recognizing the low fuel costs associated with hydro, nuclear and coal, the emission structure that pertains from central stations is that of natural gas. This means emissions of sulfur dioxide and particulate matter are nil. The impacts of generating electricity on site versus in a central station are to reduce emissions of natural gas. The reductions come from the sources below and are quantified:

a) Reduction of NO_x due to co-generation; and
b) Reduction of NO_x due to avoided delivery losses

As a result of co-generating, the need to burn gas for thermal energy is avoided. The on-site thermal energy requirement that previously required the operation of an on-site boiler, burning natural gas is avoided:

Thermal energy not generated = 4.2×10^6 BTU/H x 4×10^3 H = 16.8×10^9 BTU/yr

The thermal energy not generated leads to the following quantity of NO_x not emitted:

NO_x not emitted = 0.95 ton/10^9 BTU x 16.8 x 10^9 BTU/yr = 1.7 ton/yr; where the NO_x emission rate, for a gas-fired boiler = 0.1 ton/10^9 BTU.

At present, there is a newly emerging market for trading NO_x allowances and the prices represent the base way to establish a value. The current price is about $1200/ton.

The annual value of thermal energy not generated = $2000/yr; or

Per Unit NO_x Avoided; thermal energy not generated = $0.6 x 10^{-3}/kWh.

Reduction of NO_x due to avoided delivery losses

Due to the fact that the DG unit generates electricity the 10.8 % T&D system losses do not occur.

Annual electricity not generated = 0.11 x 3.2 x 10^3 MWH/yr = 0.35 x 10^3 MWH/yr.

The unit emissions of NO_x = 0.3 x 10^{-3} tons/ MWH, and

Annual NO_x not emitted = (0.3×10^{-3} tons/ MWH) x 0.35×10^3 MWH/yr = 0.1 ton/yr

7) Greenhouse Gas (GHG) Emission Reduction

Electricity production is a major source of GHG emissions; specifically, carbon dioxide (CO_2). An end-user-located DG unit that co-generates heat and electricity eliminates a unit to burn natural gas to generate heat. And the on-site electricity production that is highly efficient saves energy, and GHG emissions, by avoiding the T&D losses, and if the electric power system has a higher per unit GHG emission rate than natural gas, there is a third reduction. In this case we find two savings that are comprised of:

a) The avoided combustion losses arising from firing natural gas to produce heat; and
b) Avoided T&D losses reduce CO_2.

Avoided combustion = 4.2×10^6 BTU/H x 4×10^3 H/yr = 16.8×10^9 BTU/yr.

Avoided CO_2 = 16.8×10^9 BTU/yr x 0.06 tons/10^6 BTU = 1000 ton/yr.

Presently, there are no requirements to curtail emissions of CO_2. However, it has been argued that the VALUE of curbing emissions may be as high *as $US15/ton of CO_2.

The cost goal of the U.S. DOE Carbon Sequestration Program = $US15/ton of CO_2. If this were an accepted measure then, Value of Avoided CO_2 Emissions = $15,000/year.

However, using a more realistic current estimate ($2/ton),

Value of Avoided CO_2 Emissions = $2000

Per Unit Value of Avoided CO_2 Emissions = $0.6 x 10^{-3}/kWh

Avoided T&D losses reduce CO_2

- ?? A coal plants emit 1.15 tons of carbon dioxide per megawatt-hour
- ?? The mix of electricity in CA is: natural gas, 30%; hydro, 15%; gas, 12%; nuclear, 13%.
- ?? The mix of plants generates 0.5 tons of carbon dioxide per megawatt-hour
- ?? Gas plants emit 0.04 tons of carbon dioxide per 10^6 BTU or about 0.3 ton/MWH.

DG units will displace imported electricity, composition unknown, and local natural gas, the nuclear, hydro and coal fuels being much cheaper than gas. For the estimates below, it will be assumed that the displaced electricity comes from natural gas combined cycle plants.

Annual electricity not generated = 0.11 x 3.2 x 10^3 MWH/yr = 0.35 x 10^3 MWH/yr.

CO_2 Not Emitted = 0.35 x 10^3 MWH/yr x 0.3 ton/MWH = 100 ton/yr

Value of CO_2 Not Emitted = $200/year and

Per Unit Value of Avoided CO_2 Emissions = $0.6 x 10^{-4}/kWh

8) Green Energy

In this example, there are no green credits because the fuel assumed is natural gas. However, Electrotek has developed a methodology to enable a green credit to be calculated based upon current institutions that buy such credits and market them to end-use customers who wish to have their electricity, or a portion of it, supplied by green power.

The answer to who pays for, and who captures the benefits depends upon the applicable markets and the business arrangements that enable a project to go forward.

Q11: To what extent is your experience gained in eastern locations applicable to CA?

A11: The Electrotek experience is completely applicable to the situation by DG owners in CA. I explain what I mean in detail with respect to the quantified values I estimated for the typical project described above. The summary of the per unit benefits is provided below

Figure 10: CASE STUDY: Gas Engine co-Generator Benefit Analysis

Per Unit Value of Benefit	$/kWh
Capacity Value	**0.0140**
Unexpended Energy =	**0.0130**
Transmission Line Delay =	**0.006**
Avoided Distribution Investment =	**0.003**
Avoided T&D losses =	**0.001**
NO_x Avoided; thermal energy not generated	**0.0006**
Avoided CO_2 Emissions	**0.0004**
TOTAL	**0.038**

The most economically important benefits are the electric generator capacity value and the electric energy produced by the capacity. The experience Electrotek has had in quantifying these benefits in eastern states was directly applicable to the estimate we developed.

In the east, our experience has primarily been in two areas with centralized markets administered by PJM and the NYISO, respectively. Both PJM and the NYISO administer markets in which capacity is traded.

The capacity market operates by requiring each entity that supplies electricity to have sufficient capacity to meet its demand at the coincident system peak, plus to have a sufficient reserve margin. This requirement creates a market in which owners of generating capacity can sell their capacity. The capacity price is high in areas that have a shortfall and low where there is an excess of supply. In fact, where there is a shortfall (e.g., the NYISO zone serving New York City), the price of capacity clears at about $100/kW-year. This is sufficient for an independent power producer to install a combustion turbine and earn a return of about 20%; a mechanism that encourages project developers.

The existence of a capacity market is the major difference between the markets that are administered by PJM/NYISO and the market administered by the CAISO. In fact, experience in the east has taught us that only about 10% of the generators participate in market trades. Many generators have signed long-term contracts, with electricity suppliers, to supply capacity and energy. Electrotek has estimated the installed cost for a simple cycle combustion turbine ($350/kW) and the cost to operate, maintain and provide fuel. This is a very conservative way to estimate the capacity and energy costs. And, it is a conservative and fundamentally correct way to establish the value of the capacity to the CAISO. Having said that, it should be noted that the capital cost estimate used is for a unit size that is much greater than the equipment needed for the typical DG project for which the analysis was performed. That is, the capital cost estimate for the typical DG project was assumed to be $750/kW, but the comparison used ($350/kW) was for a larger central station unit. One additional element of conservatism is noted. As stated above, the current market-clearing price for capacity for capacity in New York City is about $100/kW-year. For purposes of the current estimate, it has been assumed that the value is a little more than half; or $350 x 0.16/kW-yr.

Similarly, the estimate of the value of the energy provided by the typical DG project is the fuel cost for the combustion turbine, using current fuel costs published by the U.S. DOE Energy Information Administration.

The next benefit estimated, Transmission Line Delay, benefited from the Electrotek experience in the east that enabled us to develop a methodology to estimate the benefit. The only characteristic that needs to be transferred is the specific need for a line, its length and capacity. What was done for the benefit estimate was to assume a need. While this will not be applicable to every project, there are sufficient bottlenecks in California, causing high congestion prices to make the calculation be more typical than not. California needs major transmission improvements as well as more capacity. Much of the 2001 blackouts could have been prevented by more transmission capacity. Major transmission improvements are needed on Path 15 between northern and southern California, between LA and San Diego (Path 44), on the San Francisco Peninsula, and between California and surrounding states. All of these transmission improvements are expensive, and will take many years to complete. Even the relatively simple 23.4 mile Livermore transmission project will take at least 6 years and cost $118 million. In this situation, power sources that can be built near demand would be a major advantage.

Similarly, the Distribution Line Delay benefit was calculated using the methodology Electrotek developed in the east and transferred to California by assuming the need to construct new distribution facilities. In fact, Electrotek has worked with Conectiv Power Delivery, which published a notice offering a payment per kWh for operating a DG unit in a distribution planning area that was in need of expansion. A similar offer has been made by PG&E in central California to prospective DG project developers.

The T&D Avoided Losses was done using statistics that estimate average T&D for the U.S. In fact, PGE participated in that study and the results are fairly representative of the losses experienced by an end-use customer in California.

Avoided pollution (NO_x) and CO_2 emissions estimates are based upon reductions relative to the emissions of the electrical generators that are tied to the CA grid.

Q.12: Does this conclude your testimony?

A.12: Yes.

Appendix A: Relevant Projects Conducted by Electrotek

The following list of projects has enabled Electrotek to become the premier developer and implementer of an aggregated dispatch system and the outstanding developer of methodologies to estimate the costs and benefits of potential DG projects. The projects have provided the resources to develop the technology to inter-connect, monitor, dispatch and communicate with widely dispersed DG units, and to develop the tools to evaluate the economic potential of implementing specific projects. Presently, Electrotek has aggregated over 30 MW, comprised of more than 40 end-use facilities. The list includes:

Distributed Generation Systems in a Competitive Market: The Value of DG Integration and Ancillary Services

This project demonstrated a successful analytical technique for examining the least cost approach to supplying electric power to a constrained area, and in particular, it examined ways of identifying cost-effective locations for DG installations. The project studied the Delmarva Peninsula, which is a highly constrained area where the demand for electricity is growing. Using a unique distribution system-planning tool, Distco Suite™, Electrotek quantified the benefits of locating DG technologies in specific locations; in addition, it is able to quantify the value of specific benefits (i.e., separate the value of transmission saving from ancillary services). This process provided insight into the value of specific technologies and the types of applications for which they are best suited.

DG Handbook to Estimate the Economic Benefits of a DG Project

This handbook provides potential developers of small DG projects fueled by chicken litter, with an accurate method with which to screen a potential distributed generation (DG) project that may be located within an area where the chicken litter is produced and the project is to be located at or near the premises of a customer who may use the waste heat, while the electricity is sold to a local utility or in a competitive electricity market. In fact, the handbook will enable a distribution company, as well as the customer to decide where the best location will be. Also, the question of whether the DG unit should be grid-connected or off-line can be examined and the benefits of each approach compared.

In certain critical respects the handbook will be very general. Given appropriate inputs on the DG unit and on the distribution cooperative, as well as the intended location within an electric distribution system a spreadsheet analysis can be performed that will enable the costs and benefits to be quantified and compared. Thus, the spreadsheet is the core of the handbook. The remainder of the handbook describes the required inputs, and how to select appropriate inputs for the intended DG project.

Of specific interest, the spreadsheet, actually a group of linked spread-sheets, enables the user to determine the daily fuel consumption needed to supply the DG unit, and to estimate the supply of chicken litter needed to supply the fuel requirements. In so far as the transportation distance is a critical cost factor, the methodology (using the spreadsheet) enables the unit to identify the acceptable radius for transporting the chicken litter and the number of farms within the radius needed to supply the DG unit.

DG Handbook for Industrial Facilities

This study was sponsored by ORNL for DOE. It examined the costs and benefits, from the perspective of an end-use customer of installing a DG unit to provide a number of services. While the focus is on estimating the costs of technologies of interest to the DOE Office of Energy Efficiency, the methodology contains estimates of conventional technologies (turbines and engines) to enable comparisons to be made. The Handbook contains an interactive spreadsheet that enables a user to examine the costs and benefits of a DG project. The spreadsheet outputs (through inputs provided by the user) are specific to a DG project in a specific location. The user can examine and compare alternative technologies; the study includes conventional diesel engines, micro-turbines and advanced engines.

Aggregating Distributed Generators

Many commercial and industrial facilities maintain backup generators to provide power during system emergencies that prevent the utility from delivering electricity as it normally does. In New York State, it is estimated that these backup generators have a total capacity between 6 to 10 percent of the annual peak demand. The New York State Energy Research and Development Authority (NYSERDA) are sponsoring this project to demonstrate the feasibility of aggregating these backup generators to provide peaking energy and spinning reserve capacity.

Spinning reserve capacity is traditionally provided by operating large, central-station generators below rated capacity. These generators can be ramped up to full capacity within ten minutes to meet increasing demand for electricity as needed. Utilities are required to maintain a minimum spinning reserve capacity to prevent disruptions that can de-stabilize the system when a large generator fails.

However, because the utility turbines providing spinning reserve capacity operate at less than full capacity, they are not operating at the point for maximum energy efficiency. Therefore, while these spinning reserve capacity turbines are not contributing much electricity to the utility grid, they are generating emissions. Using backup generators to provide spinning reserve capacity would avoid these emissions because the backup generators could remain idle until needed.

Since these backup generators are distributed at numerous locations within the load area, they also serve to reduce the burden on the installed transmission and distribution system. This is particularly beneficial in congested urban areas. For additional information go to: http://www.electrotek.com/new.htm

Pilot Curtailable Load Dispatch System for NYC

This study is sponsored by USDOE & NYSERDA. The first-of-its-kind project, which began operation in May 2001, has three primary goals:

- Demonstrate the feasibility of aggregating backup generating capacity through the application of controls that make the system immediately operable when required to provide interruptible loads

- Develop the control system and establish proof of concept for the aggregated system to meet emergency load curtailment program requirements

- Determine the cost-efficiency of the aggregated system necessary to attract customer interest as an alternative to the traditional approach of increasing generating, transmission and distribution infrastructure. In support of the New York Independent System Operator (NYISO), this project will set the stage for a more comprehensive emergency demand response program (EDRP).

Under the project, Electrotek is to recruit existing backup generators with a combined capacity of four to six megawatts. To date, Electrotek has recruited more than 20 megawatts of capacity for aggregation this summer. For additional information go to: http://www.electrotek.com/new.htm.